TECHNICAL REVIEW DOCUMENT
for
MODIFICATION TO OPERATING PERMIT 97OPWE180

Public Service Company, Ft. St. Vrain Station
Weld County
Source ID 1230023

Prepared by Jacqueline Joyce
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Revised November 2002, February and May, 2003

I. Purpose:

This document establishes the decisions made regarding the requested modifications to the Operating Permit for Ft. St. Vrain Station. This document provides information describing the type of modification and the changes made to the permit as requested by the source and the changes made due to the Division's analysis. This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the information provided in the original requests for modification submitted to the Division on February 27 and July 26, 2002, additional technical information received January 23 and March 21, 2003, comments on the draft modified permit and technical review document received on December 26, 2002 and March 13, 2003, comments on the draft modified permit and technical review document received during the Public Comment period, various e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Permit Modification Request/Modification Type

The Operating Permit for Ft. St. Vrain Station was issued on January 1, 2000. Public Service Company (PSCo) submitted a request to modify the permit on

February 27, 2002 to incorporate the applicable requirements for Turbine 4 into the operating permit. The applicable requirements for Turbine 4 are contained in Colorado Construction Permit 99WE0762 PSD. In addition, the source requested that the heat input limit for turbine 4 be calculated using a different methodology, which results in an increased heat input limit for the unit. Incorporating the applicable requirements from Colorado Construction Permit 99WE0762 PSD is considered a significant modification to the operating permit and requires a 30-day public comment period and a 45-day EPA review period. Since turbine 4 was issued Colorado Construction Permit 99WE0762, the unit may operate under the conditions of that permit until issuance of the operating permit.

In addition PSCo submitted an application on July 26, 2002 to correct a typographical error in the cooling tower VOC emission limits. In the original Title V operating permit processing the source requested an increase in the circulating water limit and the increase in the VOC emission limitation, which is directly based on the water circulation rate, was inadvertently not included in the permit. This modification was classified as an administrative amendment, however, the source requested that the administrative amendment be included with the significant modification in progress. Since the increase to the VOC emission limits was classified as an administrative amendment, the source may operate under the change upon submittal of the complete application and need not wait for the revised permit to be issued. Therefore, the increase in the VOC emission limit for the cooling tower was considered to be effective on July 26, 2002.

III. Modeling

Modeling was conducted for Turbine 4 as part of the issuance of the construction permit. The only change from the existing construction permit that PSCo is requesting is the increase in heat input limit. PSCo has requested no increase in emissions for this change. Therefore, no additional modeling is required for Turbine 4. This modification also results in a minimal increase (0.1 tpy) in permitted VOC emissions for the cooling tower and no modeling is required.

IV. Discussion of Modifications Made

Source Requested Modifications

The source’s requested modifications were addressed as follows:

Change in Method of Determining Heat Input Limit for Unit 4

The permitted heat input limits for the Unit 4 combustion turbine are based on manufacturer’s heat input ratings for the turbine. The manufacturer’s heat input rate for the turbine varies with the ambient temperature. The permitted heat input limit in the construction permit is based on the turbine operating at a 90% capacity factor (7,884 hrs/yr) and 25% of the time at 0 º F, 25% of the time at 90 º F and 50% of the time at 60 º F. In their request received on February 27, 2002 to modify the Title V operating permit, PSCo requested that the permitted heat input limit be based on more accurate temperature data. Although summer temperatures certainly reach 90 º F and above, the source has indicated that the unit is equipped with an inlet air cooler which maintains the inlet air temperature at 60 º F. Therefore, the source has requested that the heat input limit be based on an average annual inlet air temperature of 50.7 º F. This average value is based on 3 years of continuous monitoring data from the Unit 2 turbine. The heat input rate for the turbine, at 50.7 º F is 1,530.5 mmBtu/hr and based on a capacity factor of 90% the requested heat input limit is 12,066,462 mmBtu/yr.

The increased heat input limit will be included in the operating permit as requested by the source. The Division considers that the increase in the heat input limit is not considered a change in the method of operation, since the change is due to a revised calculation methodology based on more realistic data and not the result of increased operation.

Since the permitted SO_2 emissions are based directly on the permitted heat input limit and an emission factor, the source requested an increase in SO_2 emissions from 4.5 tons/yr to 4.7 tons/yr. This change will be made as requested in the operating permit.

Combustion Tuning of Turbines

In their comments on the draft revised operating permit, received on December 26, 2002, the source requested that the alternative BACT limits startups and shutdowns be applicable during periods of combustion tuning. The source indicated that when the plant performs a major overhaul on the combustion turbines, which is typically every 18 months, or experiences problems with the combustion control system, the manufacturer’s engineers are brought onsite to retune the engines. Typically the combustion tuning is done during an extended startup after an outage, since the tuning is done when the turbine is operated in modes 1 – 5. However, there may be occasions where the tuning may be done at some time after a start up. During such tuning operations the turbine is performed at modes 1 – 5 at low load conditions. The Division has agreed to allow the startup and shutdown BACT limits to apply during periods of combustion tuning for 30 hrs/yr per turbine.

Revised Quality Control Requirements for ByPass Stack

The source indicated that they are using the provisions in 40 CFR Part 75 § 75.17(d) for units with a main stack and a bypass stack, which became effective on June 12, 2002. These provisions allow sources to install, certify, operate and maintain a NO_X and diluent CEMS only on the main stack. For each unit operating hour in which the bypass stack is used, the source must report the maximum potential NO_X emission rate. The source has indicated that they will use the maximum potential NO_X emission rate for any hour that the unit is operating in simple cycle mode (bypass stack is used) to monitor compliance with the annual NO_X limit. However, in order to monitor compliance with the NO_X BACT limit, the source must retain their CEMS system on the bypass stack. Since 40 CFR Part 75 does not require a CEMS for the bypass stack and since the bypass stack is operated very infrequently, the source has requested that less stringent quality assurance/quality control (QA/QC) requirements be applied to the bypass stack.

The source has indicated that the analyzers used to measure NO_X and CO emissions are common to both the bypass and HRSG stacks. Each unit (turbine plus HRSG and duct burner) has a single NO_X and CO analyzer that pulls a sample from either the bypass or HRSG stack, dependent upon which is in operation. The only equipment unique to each stack is the sample line and the stack probe. The alternative QA/QC requirements proposed by the source and have been approved by the Division and will be included in Appendix G of the permit.

<u>Addition of Turbine 4</u>

Turbine 4 is a GE natural gas-fired combustion turbine, Model No. PG7241 (FA), Serial No. 297457, equipped with one (1) Vogt-NEM heat recovery steam generator and natural gas-fired duct burner rated at 422 mmBtu/hr. The turbine is equipped with a low NO_X combustion design and is rated at 141.7 MW. The HRSG/duct burner combination provides an additional 100 MW of electricity. The HRSG is equipped with selective catalytic reduction (SCR) to reduce NO_X emissions.

Construction permit 99WE0762 PSD was issued for Turbine 4 on June 19, 2000 (initial approval). Construction on this unit commenced in April 2000, prior to issuance of the construction permit. In order to be able to meet future power demands, construction of this unit needed to begin by April 15, 2000 and a Compliance Order on Consent was issued on April 13, 2000 to allow construction of the unit to begin. Turbine 4 commenced commercial operation in April 2001. Construction permit 99WE0762 PSD was revised and reissued as a final approval permit on February 27, 2002.

Applicable Requirements

Turbine 4 is subject to the following applicable requirements from Colorado Construction Permit 99WE0762:

- Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 1 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation". The 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

- This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO_X), Carbon Monoxide (CO) and Particulate Matter (condition 3).

NO_X:

Combined Cycle Mode (condition 3.a):

BACT is defined as DLN combustion for the turbine and SCR for the HRSG with NO_X emissions limits as follows:

- o Except as provided for below, emissions not to exceed 4 ppmvd at 15% oxygen on a 24-hour average.
- o During startup and shutdown, NO_X emissions shall not exceed 100 ppmvd at 15% oxygen on an hourly average.

Simple Cycle Mode (condition 3.b):

BACT is defined as DLN combustion for the turbine with NO_X emission limits as follows:

- o Except as provided for below, emissions not to exceed 9 ppmvd at 15% oxygen on a 24-hour average.
- o During startup and shutdown, NO_X emissions shall not exceed 100 ppmvd at 15% oxygen on an hourly average.

As discussed above under "combustion tuning", the Division will allow the startup and shutdown BACT limit to apply during periods of combustion tuning. The Division has limited the use of the higher BACT limit for combustion tuning to 30 hrs/yr for each turbine.

Combustion tuning is defined as operation of the unit for the purpose of performing combustion tuning operations after a unit overhaul or as part of routine maintenance operations. Combustion tuning begins when the unit is operated in modes 1 through 5 for the purpose of tuning the unit and ends when mode 6 operation is reached.

CO:

Combined Cycle Mode (condition 3.c):

BACT is defined as good combustion practices/monitoring systems with CO emission limits as follows:

- o Except as provided for below, when fuel is fired in the duct burner, emissions not to exceed 20 ppmvd at 15% oxygen on an hourly average.
- o Except as provided for below, when fuel is **not** fired in the duct burner, emissions not to exceed 9 ppmvd at 15% oxygen on an hourly average.
- o During startup and shutdown, 2,060 lbs/hr and 1,000 ppmvd at 15% oxygen on an hourly average.

Simple Cycle Mode (condition 3.d):

BACT is defined as good combustion practices/monitoring systems with CO emission limits as follows:

- o Except as provided for below, emissions not to exceed 9 ppmvd at 15% oxygen on an hourly average.
- o During startup and shutdown, 2,060 lbs/hr and 1,000 ppmvd at 15% oxygen on an hourly average.

As discussed above under "combustion tuning", the Division will allow the startup and shutdown BACT limit to apply during periods of combustion tuning. The Division has limited the use of the higher BACT limit for combustion tuning to 30 hrs/yr for each turbine.

Combustion tuning has the same definition as discussed above under the NO_X BACT limits.

PM and PM_{10} (condition 3.e):

- o Pipeline quality natural gas shall be used to minimize the formation of particulate matter, both filterable and condensable.

Definition of Startup and Shutdown (condition 3.f):

- o Startup is defined as the time period between initial fuel firing to combustion configuration Mode 6. Mode 6 refers to the condition when all six burner nozzles are being fired. The station control system indicates which Mode the turbine is operating in. A record of when Mode 6 combustion configuration is achieved is stored in the station control system.
- o Shutdown begins when the command signal is initiated by the turbine

operator to shutdown the unit and ends when fuel is no longer being fired in the turbine.

The definition of startup and shutdown were revised so that the definition of startup and shutdown in the permit does not conflict with the definitions of startup and shutdown in C.R.S. §§ 25-7-103.(20) and (21).

- Normal operation begins when the unit achieves Mode 6 operation following a startup and ends when the command signal to shutdown the unit is initiated.

  EPA has indicated in comments on other operating permits that they consider start-up and shutdown part of "normal" operations. Therefore, the use of the term "normal" shall be avoided in discussing BACT limits for this unit.

- The permittee shall maintain records of the number of startups and shutdowns and the duration of each period. These records shall include the date of the event, the time the event began and the time the event was completed. These records shall be made available to the Division upon request.

  Since the source is required, in accordance with 40 CF Part 60 Subpart A § 60.7(b), to record startups and shutdowns and their duration, it is not necessary to include the above language in the permit.

- The normal operation hourly average limits shall apply beginning with the first full hour following Mode 6 operation. The normal operation 24-hour average limits shall apply beginning with the 25th hour after Mode 6 operation. A new 24-hour average will be calculated each successive hour using data for the previous 24 hours.

  The above language regarding the application of the 24-hour normal operations BACT limits (4 ppmvd and 9 ppmvd NO_X) is misleading and needs to be revised. First of all, the Division considers that the limits apply beginning with the 1st full hour after startup ends, although based on the averaging time, compliance cannot be determined until 24 hours of data have been recorded. The current language seems to imply that the first 24 hours of normal operation don't count in considering compliance with the BACT limits. Therefore, the Division will revise the language to state that the limits apply with the first hour of operation, however, compliance is not determined until after 24 hours of operation have occurred.

  The Division considers that the 24-hour averaging time could be problematic as there could be situations where the unit operates for less than 24 hours and as a result NO_X emissions are never used to assess compliance. Such situation would be if the time between startup and shutdown is less than 24 hours and if the unit operates in a given mode (i.e. simple cycle) less than 24 consecutive hours.

In the first instance, since the unit was operated for less than 24 hours between startup and shutdown, those NO_X emissions during that period would not be used in considering whether the BACT limit had been met. The source has indicated that this unit is a baseload unit and that the once the unit is started up it is not shutdown unless there is a problem with the unit or maintenance is planned.

In the second case, if the unit was operated for less than 24 consecutive hours in a given mode, the NO_X emissions during that period would not be used in considering whether the BACT limit had been met. The source has indicated that the unit is usually operated in combined cycle mode and usually without burning fuel in the duct burners as this is the most efficient operating mode. They have indicated that the unit is rarely operated in simple cycle mode and the unit is unlikely to operate for 24 consecutive hours in simple cycle mode. Depending on the quantity of NO_X emissions that are never compared to a BACT limit and assessed for compliance, the Division may feel it is necessary to add a provision to the BACT limit to require a daily average rather than a 24-hour average for those periods where less than 24-hours of consecutive data is obtained. Therefore, the permit will require that the source identify and submit data indicating the number of hours of NO_X emissions that are not used in assessing compliance with the BACT limits, the mode (or modes) the unit was operated in during those hours and the percentage of total operating time that those hours represent. In the event that there is a significant number of hours of NO_X emissions that are not used in a compliance assessment, the Division will reopen the permit to revise the NO_X BACT limits as discussed above.

- A continuous emission monitoring system (CEMS) shall be installed, calibrated and operated to determine and record the following (condition 4):

  - Combustion fuel flow rate on the natural gas line
  - Concentration of NO_X, ppmvd 24-hour average, rolling 12-months

    Note that since the startup and shutdown NO_X BACT limits are hourly averages, the CEMS must also record the ppmvd hourly average.

  - Emissions of NO_X, tons/month, tons/rolling 12-months.
  - Concentration of CO, ppmvd hourly average, in the exhaust.
  - Emissions of CO, tons/month, tons/rolling 12-months.

    Note that since the startup and shutdown CO BACT limit includes a lbs/hr element, the CEMS must also record the lbs/hr.

  - Concentration of oxygen, percent hourly average, in the exhaust.

- The CEMS is also subject to the following requirements (condition 4):

  - Quality assurance/quality control shall conform to 40 CFR Part 60,

Appendix F, and Subpart A.

- Provisions of 40 CFR Part 60, Subpart A – General provisions, shall be followed for notification, recordkeeping, and monitoring.
- When quality assured data is not available for NO_X and CO, the missing data substitution procedures in 40 CFR Part 75 Subpart D shall be followed. Although CO emissions are not specifically referenced in the Subpart D procedures, the CEM data acquisition system will be programmed to substitute CO emissions using the same procedures specified for NO_X.
- The CEMS data shall be used to determine compliance with emission limits for NO_X and CO.

- The turbine is subject to Regulation No. 6 - Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart GG - Standards of Performance for Stationary Gas Turbines (condition 5):

  - NO_X emissions shall not exceed 112 ppmvd, at 15% O_2 at ISO standard conditions (compliance with the BACT limits will satisfy this NSPS requirement).

    The construction permit states that compliance with the BACT limits satisfy the NSPS requirements. In addition, the construction permit indicates that the averaging time for the NO_X limit is a 3-hour average, which is not correct. The averaging time for the NO_X limit is not specifically identified in the regulation, however, a recent EPA determination (control # 0000055, dated April 6, 2000, from EPA Region 4 (R. Douglas Neeley)) indicated that the NSPS GG averaging time is 1 hour. This is consistent with language in the regulation that specifies that excess NO_X emissions are any one hour period that the water-to-fuel ratio falls below that level determined to show compliance with the performance test (40 CFR Part 60 Subpart GG § 60.333(c)(1)). The averaging time for the BACT limit (4 ppmvd combined cycle and 9 ppmvd simple cycle) is 24-hours. Although the averaging time is different for the BACT and the NSPS limits, the Division would still consider it unlikely that the NSPS GG limit of 112 ppmvd would be exceeded without exceeding the BACT limit also, therefore, we consider that it is still acceptable to say that compliance with the BACT limit will satisfy the NSPS limit.

  - SO_2 emissions shall not 150 ppmvd at 15% O_2 **or** sulfur content in the fuel shall not exceed 0.8 % by weight. Compliance with the SO_2 limit shall be presumed when burning pipeline quality natural gas.

- The duct burner/HRSG is subject to Regulation No. 6 - Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units (condition 6):

- o Particulate matter emissions shall not exceed 0.03 lbs/mmBtu (§ 60.42a(a)(1))
- o Opacity of emissions shall not exceed 20% opacity (6-minute averages), except for one six-minute period not to exceed 27% (§ 60.42a(b))
- o SO_2 emissions shall not exceed 0.20 lbs/mmBtu, on a 30-day rolling average (§ 60.43a(b)(2))

  Note that 40 CFR Part 60 Subpart Da § 60.43a(b)(2) specifically states that the SO_2 limitation is "100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.2 lbs/mmBtu". Since these units burn natural gas, emissions will be below 0.2 lbs/mmBtu (40 CFR Part 75, Appendix D allows sources burning pipeline quality natural gas to use a default emission factor of 0.0006 lbs/mmBtu). Because emissions are below 0.2 lbs/mmBtu the source may emit 100% of the potential combustion concentration, i.e. no limits. However, since this "no SO_2 limits" only applies if emissions are below 0.2 lbs/mmBtu, the Division included the upper bound of 0.2 lbs/mmBtu as the emission limitation.

- o NO_X emissions shall not exceed 0.2 lbs/mmBtu. Compliance with the BACT limits will satisfy this NSPS requirement.

  The NO_X limit included in the construction permit is not correct. NSPS Subpart Da was revised September 16, 1998 and established different NO_X limitations for sources that commenced construction or modification after July 9, 1997. Since the duct burner/HRSG commenced construction after July 9, 1997 the new NO_X standard of 1.6 lbs/MW-hr in 40 CFR Part 60 Subpart Da § 60.44a(d)(1) applies to this unit.

Although not included in the construction permit, the following requirements from NSPS Da also apply:

- o Compliance with the NSPS requirements shall be monitored in accordance with the requirements in 60.46a and 60.47a, including but not limited to the following:
  - Demonstrate compliance with the NO_X emissions in accordance with the requirements in § 60.46a(k).

    The construction permit indicated that compliance with the NO_X BACT limit is compliance with the NSPS NO_X limit. Although the construction permit contained the wrong NSPS NO_X limit, the source submitted information with their comments on the draft permit (received December 26, 2002) indicating that the correct NSPS NO_X limit was still more stringent than the NO_X BACT limit of 4 ppm. Based on the language in the construction permit the source presumed that a performance test for the NSPS NO_X limit would not be required. Although the

Division may agree that the NSPS NO_X limit may be streamlined in favor of the more stringent NO_X BACT limit, the Division does not believe that the requirement to conduct an initial performance test for the NSPS NO_X limit can be streamlined.

Recently, EPA made revisions, effective June 11, 2001, to NSPS Subpart Da in order to more appropriately address duct burners. These revisions provided two methods for combined cycle units (turbine plus duct burner) to demonstrate compliance with the NO_X emission limits and specified that owners or operators of duct burners are not required to install the continuous monitoring systems for NO_X emissions, watts and steam characteristics. Owners or operators of combined cycle units may demonstrate compliance with the NO_X emission limits by either conducting a stack test (3 one-hour tests) or using NO_X continuous emission monitors. Although Unit 4 commenced operation before the revisions to NSPS Subpart Da were effective, the effective date is within the 180-day window to conduct the initial performance test. Therefore, the Division believes and EPA has agreed that the source may demonstrate compliance with the NSPS NO_X limit with a 3-hr performance test and that NO_X CEMS are not required for combined cycle units.

The Division considers that the initial performance tests that have already been conducted (May 10 – 12, 2001, for simple cycle mode and June 27 – 29, 2002 for combined cycle mode) may be used to demonstrate compliance with the NSPS Da NO_X limits.

- Install and operate a continuous emission monitor for NO_X and either CO_2 or O_2 (§§ 60.47a(c) & (d))
- Minimum data requirements (§ 60.47a(f))
- Supplementing data (§ 60.47a(h))
- Install and operate a wattmeter (§ 60.47a(k))

Since the source has demonstrated compliance with the NO_X Da limit by conducting a performance test, the above requirements do not apply. As specified in 40 CFR Part 60 Subpart Da § 60.47a(o) a NO_X CEMS and wattmeter are not required for combined cycle units.

- Performance tests shall be conducted in accordance with the requirements in § 60.48a(f).

The source has already conducted a performance test for PM. A performance test for SO_2 was not required because the unit burns natural gas as fuel so a compliance test for SO_2 is not necessary.

Although the construction permit contained the wrong NSPS Da NO_X limit, the Division has determined that the performance tests already conducted may be used to demonstrate compliance with the NSPS Da NO_X limit. Therefore, no performance test requirements will be included in the operating permit. However, it should be noted that the Division has not approved the performance tests yet and the Division may require further testing in order to approve the initial compliance test. If necessary, the permit may be reopened as a result of the Division's review of these initial performance tests.

- Reporting requirements in § 60.49a

  The source has already submitted the performance test data from the initial performance test as required by 40 CFR Part 60 Subpart Da § 60.49a(a) so this requirement shall not be included in the operating permit. In addition, as discussed previously, since the source elected to demonstrate compliance with the NSPS Da NO_X limits with the one-time performance test, the NSPS Da NO_X CEMS requirements do not apply and therefore, the remaining reporting requirements (all others that potentially apply to this unit are related to CEMS), also do not apply.

- The turbine/HRSG/duct burner are also subject to the requirements in 40 CFR Part 60 Subpart A – New Source Performance Standards – General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A, the following will be included in the permit (condition 7):

  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

  Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the operating permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

  In addition, the permit included the requirement for excess emission reports (40 CFR Part 60 Subpart A § 60.7(c)). The NSPS specifies that these reports shall be submitted semi-annually, except when more frequent reporting is required by the applicable subpart or if the Division determines that more frequent reporting is necessary to accurately assess the compliance status of the emission unit. The Division has determined that more frequent reporting is necessary and therefore, excess emission reports shall be submitted quarterly.

- The source is subject to Regulation No. 6 – Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, D – Standard for Sulfur Dioxide, 3 – Combustion Turbines SO_2 emissions shall not exceed 0.35 lbs/mmBtu (condition 8). This is a **state-only requirement**.

  Although not specifically identified in the construction permit, the turbine and duct burner are also subject to the 20% opacity requirement in Section II.C.3.

- The permittee shall maintain records demonstrating that the natural gas burned has a hydrogen sulfide content less than 0.3 grains/100 SCF (condition 9).

  Note that this is the definition of pipeline quality natural gas in 40 CFR Part 72, however that definition was revised June 12, 2002 and the new definition of pipeline quality natural gas (0.5 grains or less of total sulfur per 100 SCF) will be included in the permit.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request. Compliance with the annual consumption limits shall be determined on a rolling twelve (12) month total (condition 10).

  - Natural gas consumed by the turbine shall not exceed 11,974,561 mmBtu/yr
  - Natural gas consumed by the duct burner shall not exceed 3,157,702 mmBtu/yr

  Note that in the permit the turbine gas consumption limit was increased to 12,066,462 mmBtu/yr as discussed previously under "change in method of determining heat input limit" based on the new calculation method.

- Emissions of air pollutants shall not exceed the following limits (condition 11):

  - PM 54 tons/yr
  - PM_{10} 54 tons/yr
  - SO_2 4.5 tons/yr
  - NO_X 199.1 tons/yr
  - VOC 33.1 tons/yr
  - CO 237.9 tons/yr

  Note that as discussed previously under "change in the method of determining heat input limit" the SO_2 emission limit was increased to 4.7 tons/yr in the permit.

- An annual report shall be submitted to the Division, by April 30, for the previous calendar year. This report shall contain, at a minimum, the following (condition 12):

    - Consumption of natural gas
    - Total emissions of all pollutants as determined by the CEMS
    - Episodes of emission exceedances
    - Certification of compliance/non-compliance of permit conditions
    - Upset conditions and remedial measures taken

  With the issuance of the operating permit the source will be required to certify annually that they are in compliance with the conditions in the operating permit, which includes compliance with the emission limitations, fuel consumption limits and reporting requirements (including APEN reporting and excess emission reports). The majority of the information that the source is required to include in this annual report is already required to be reported under APEN (fuel consumption and annual emissions) and excess emission reporting requirements. Therefore, this requirement will not be included in the operating permit.

- This source is subject to the odor requirements of Regulation No. 2 (condition 13)

  Turbines, with or without duct burners, are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section V) of the permit.

- APEN reporting (condition 14 and Colorado Regulation No. 3, Part A Section II.C)

  The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in Colorado Construction Permit 99WE0762 PSD, the turbine/HRSG/duct burner are subject to the following applicable requirements:

- Particulate matter emissions from the duct burner shall not exceed $0.5(FI)^{-0.26}$ lbs/mmBtu, where FI is the fuel input in mmBtu/hr (Reg 1, Section III.A.1.b)

- Particulate matter emissions from the turbine shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)

  When the turbine and duct burner are operated together (shared stack per

Reg 1, Section III.A.1.d), the particulate matter emission limit is calculated as follows:

$$PE = \frac{\underline{(0.1\ lbs/mmBtu \times 1530.5\ mmBtu/hr) + (0.5 \times (466)^{-0.26}\ lbs/mmBtu \times 466\ mmBtu/hr)}}{1530.5\ mmBtu/hr + 466\ mmBtu/hr} = 0.1\ lbs/mmBtu$$

- Sulfur dioxide emissions from the turbine shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)

- This unit subject to the Acid Rain requirements as follows:
  - Allocated SO_2 allowances are listed in 40 CFR Part 73.10(b), however, since this is a new unit, no allowances were allocated. SO_2 allowances must be obtained per 40 CFR Part 73 to cover SO_2 emissions for the particular calendar year.
  - There are no NO_X emission limitations since this unit is not a coal-fired boiler.
  - Acid rain permitting requirements per 40 CFR Part 72.
  - Continuous emission monitoring requirements per 40 CFR Part 75.
  - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission units that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. Turbine 4 is subject to a variety of NO_X emission limitations, is equipped with control equipment to reduce NO_X emissions and has potential NO_X emissions above major source levels. Therefore, the turbine is subject to CAM. The application to modify the Title V operating permit to add Turbine 4 was submitted on February 27, 2002 and this modification is considered a significant modification. Since the potential to emit of NO_X for this unit, including controls, exceeds the major source level, CAM applies to this unit at this time, rather than at renewal. Therefore, CAM requirements are being included in the revised operating permit for Turbine 4 only.

NO_X emissions from Turbine 4 are controlled by DLN for the turbine and SCR for the HRSG. DLN is not considered a control device as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since the DLN combustion system is considered inherent process equipment. However, the SCR on the HRSG does meet the definition of a control device, therefore, CAM applies to the turbine/HRSG, when operated in combined cycle mode, provided the unit is subject to an emission limitation and uses the control device to comply with the emission limitation. When operating in combined cycle mode, the turbine/HRSG is subject to BACT limits (4 ppmvd, on a 24-hour average and 100 ppmvd, on a 1-hr average during startup, shutdown and combustion tuning), an NSPS Da NO_X limit (1.6 lbs/MW-hr, on a

30-day rolling average) and an annual NO_X limit (199.1 tons/yr). SCR is required to meet the 4 ppmvd NO_X BACT limit. The 100 ppmvd NO_X BACT limit applies to the turbine only (simple cycle operation) also. Therefore, the Division considers that SCR is not required to meet the 100 ppmvd NO_X BACT limit. The NSPS Da NO_X limit applies to the duct burner only, however, the duct burner is not operated without the turbine and the duct burner exhausts through the HRSG stack, which is equipped with SCR. Therefore, the Division considers that CAM applies to Turbine 4, when operated in combined cycle mode, with respect to the 4 ppmvd NO_X BACT limit for combined cycle operation and the NSPS Da NO_X limit. Note that as discussed later, the NSPS Da NO_X limit has been streamlined from the permit in favor of the more stringent NO_X BACT limit. When operated in combined cycle mode, the turbine/HRSG is also subject to an annual NO_X limitation. However, this annual limitation is based on the unit operating in simple cycle mode (turbine only) and SCR is not necessary to meet this annual limitation. Therefore, the Division considers with respect to the annual NO_X limitation that CAM does not apply.

Streamlining of Applicable Requirements

<u>Opacity</u>

The turbine, itself (simple cycle mode and combined cycle mode with no supplemental fuel) is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbine is also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other <u>at all times</u>, all three opacity requirements are included in the operating permit.

The duct burner (combined cycle mode with supplemental fuel) is subject to the opacity requirements mentioned above and is also subject to the NSPS opacity requirements. Since the duct burner would not be operated without the turbine and since the duct burner and turbine share a stack, for all practical purposes the turbine and duct burner combination together are subject to NSPS opacity requirements. The NSPS opacity requirements are not applicable during periods of startup, shutdown and malfunction in accordance with the requirement in 40 CFR Part 60 Subpart A § 60.11(c). The NSPS opacity requirements are more stringent than the Reg 1 30% requirements under all the specific operating conditions except startup but are less stringent than the state-only Reg 6 requirements. The Reg 1 (20%/30%) opacity requirements are more stringent than the NSPS requirements during startup, shutdown and malfunction. Again, since no one opacity requirement is more stringent than the others at all times, all four opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency

It should be noted that since the turbine and duct burner use natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

SO_2

Only the Regulation No. 1, Regulation No. 6, Part B (which only apply to the turbine) and NSPS Subpart Da (which only applies to the duct burner) SO_2 requirements are in the same units and can therefore be compared for the purposes of streamlining.

The Regulation No. 1 and No. 6, Part B SO_2 standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "…it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO_2 requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 SO_2 requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The NSPS Subpart Da requirement of 0.2 lbs/mmBtu applies to the duct burner and the Reg 1 SO_2 requirement applies to the turbine. Since the duct burner would not be operated without the turbine and since the duct burner and turbine share a stack, for all practical purposes the turbine and duct burner combination together are subject to the Reg 1 and the NSPS Da SO_2 requirements. Although the NSPS Da requirement of 0.2 lbs/mmBtu appears to be more stringent than the Regulation No. 1 requirement, the NSPS Da requirement is based on a 30-day rolling average and the Reg 1 requirement is on a 3-hour rolling average. It is likely that the Reg 1 limit could be violated without violating the NSPS Da requirement. Therefore, these requirements cannot be adequately compared for stringency so both requirements will be included in the operating permit.

This unit (turbine/HRSG/duct burner) is also subject to the Acid Rain SO_2 requirements. Sources subject to Acid Rain must hold adequate SO_2 allowances to cover annual emissions of SO_2 (1 allowance = 1 ton per year of SO_2) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both the federal requirement and the Acid Rain requirement shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO_2 requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with the Acid Rain SO_2 requirements and the Reg 1 and NSPS Da SO_2 requirements. Note that the Acid Rain SO_2 allowances appear only in Section III (Acid Rain Requirements) of the permit.

NO_X

Since the NSPS Subpart GG and BACT concentration limits are in the same units, they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the SO_2 streamlining section above). The BACT NO_X limits are much more stringent than the NSPS limits (4 or 9 ppmvd vs 112 ppmvd), however the averaging times are different (24-hr for BACT and 1-hr for NSPS). Since the BACT limits are so much lower than the NSPS limits, the Division considers that even with the 24-hr BACT averaging time that if one hour of NO_X emissions exceeded 112 ppmvd that the BACT limit would also be violated. Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, the NSPS Subpart GG limits will be streamlined out of the operating permit.

Note that streamlined conditions are subsumed within the requirements identified in Section II of the permit. For purposes of compliance demonstration, compliance with the conditions in Section II of the permit also serve as compliance demonstration for the subsumed condition. Since the NSPS GG NO_X limit has been streamlined out in favor of the BACT NO_X limits, the source may wish to retain records of ambient temperature and humidity data which is used to convert NO_X values to ISO standard day conditions, in the event that the NO_X BACT limit is violated at such a level that compliance with the NSPS GG BACT limit is uncertain.

The duct burner is subject to an NSPS Subpart Da NO_X limit of 1.6 lbs/MW-hr gross energy output, on a 30-day rolling average. In their comments on the draft permit (received December 26, 2002), the source submitted information demonstrating that the NSPS Da NO_X limit is less stringent than the NO_X BACT limit. The Division agrees and therefore, the NSPS Da NO_X limit has been streamlined out of the permit in favor of the NO_X BACT limit.

PM

The turbine and duct burner (alone and together) are subject to a Reg 1 particulate matter standard and the duct burner is subject the NSPS Da particulate matter standard. Since the duct burner would not be operated without the turbine and since the duct burner and turbine share a stack, for all practical purposes the turbine and duct burner combination together are subject to NSPS Da particulate matter standard. Although the NSPS Da particulate matter standard appears to be more stringent (0.03 lbs/mmBtu vs ~ 0.1 lbs/mmBtu), neither requirement can be streamlined out of the permit since the NSPS Da requirement does not apply during periods of startup, shutdown and malfunction, as specifically stated in § 60.46a(c), but the Reg 1 particulate matter standard applies at all times. Therefore, during certain periods (i.e. startup, shutdown and malfunction), the Reg 1 particulate matter standard is more stringent. Therefore, both the Reg 1 and the NSPS Da particulate matter standards are included in the operating permit.

Monitoring Requirements

This unit (turbine/HRSG/duct burner) is subject to several types of monitoring requirements. The construction permit requires that the stacks be equipped with continuous emission monitoring systems (CEMS) to monitor and record NO_X and CO emissions and the construction permit requires that these monitors be installed, maintained, calibrated and operated according to 40 CFR Part 60, Appendix F and Subpart A. This unit is also subject to the Acid Rain requirements and as such is required to monitor emissions in accordance with the requirements in 40 CFR Part 75. The duct burner is subject to NSPS subpart Da. For combined cycle units (turbine plus duct burner) NSPS Da allows compliance with the NO_X requirements to be demonstrated with either a one-time performance test or a CEMS. NSPS Da specifically states that combined cycle units are not required to have NO_X CEMS (40 CFR Part 60 Subpart Da § 60.47a(o)). Since the source demonstrated compliance with the NSPS Da NO_X limit with a one-time performance test, the NSPS Da NO_X CEMS requirements do not apply to the duct burner and therefore need not be considered further for purposes of streamlining.

Since the source has installed Part 75 NO_X (and diluent) CEMS, the permit will specify that the NO_X (and diluent) CEMS must meet the requirements in 40 CFR Part 75. The construction permit requirement to install NO_X and diluent CEMS that meet Part 60 requirements will be streamlined out of the permit in favor of the Part 75 requirements.

It should also be noted that the 40 CFR Part 60 excess emission reporting requirements for NO_X will remain in the permit as 40 CFR Part 75 does not contain any NO_X excess emission reporting requirements.

NSPS Subpart GG requires daily sampling of fuel to determine the nitrogen and sulfur content of the fuel. In an August 14, 1987 memo, the EPA waived the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas. The Acid Rain requirements allow sources that burn natural gas to use an alternate monitoring method in lieu of a continuous emission monitor for SO_2. These requirements are in 40 CFR Part 75, Appendix D. Specifically, this monitoring method requires the source to monitor fuel fed to the combustion turbine for every hour that it combusts fuel. The source may then either sample and analyze natural gas for sulfur content or they may use the default SO_2 emission factor to determine SO_2. The default emission factor may be used if pipeline quality natural gas is burned. In order to use the pipeline quality natural gas default emission factor, the source must demonstrate using any of the methods in 40 CFR Part 75, Appendix D, Section 2.3.1.4 that the fuel has a total sulfur content of less than 0.5 grain/100 SCF. The source is using the default emission factor provided by Part 75 Appendix D for the purposes of determining SO_2 emissions. Therefore, the NSPS Subpart GG requirement to sample fuel daily for sulfur content will be streamlined out of the permit in favor of the Part 75 pipeline quality natural gas requirement. It should be noted that EPA determinations support the use of the “Optional Sulfur Dioxide Emissions Data Protocol for Gas-Fired and Oil-Fired Units” of Appendix D of 40 CFR Part 75 as a custom fuel monitoring schedule for SO_2 (March 13, 2000 letter from John Hepola to Daniel Ewan, re “Approval of Alternative Monitoring for NSPS Subpart GG Pine Bluff Energy, LLC – Pine Bluff Energy Center Pine Bluff, Arkansas Operating Air Permit # 1822-AOP-R0”, Control Number 0000015, from EPA Region 6).

Emission Factors

The source will be monitoring compliance with the NO_X, CO and SO_2 emission limitations using their continuous monitoring systems. NO_X and CO are measured using continuous emission monitoring systems and SO_2 is monitored using the continuous monitoring system required by 40 CFR Part 75 Appendix D, which requires an in-line fuel flow meter to measure the hourly consumption of natural gas and bases emissions on the heat input and a default emission factor of 0.0006 lbs/mmBtu.

The emission limits in the construction permit are based on manufacturer's estimates for PM, PM_{10} and VOC. However, stack tests were conducted for PM (including condensibles) and VOC emissions and the source is using the emission factors from the performance tests to monitor compliance with the emission limits.

The PM tests were conducted on May 10 – 12, 2001 for the turbine only and on June 27-29, 2001 for the HRSG stack (with fuel fired in the duct burner). The source has proposed to use the higher emission factor for estimating emissions and will use that emission factor for all operating modes. The highest PM emission factor (including condensibles) is 0.005 lbs/mmBtu and this value is from the test on the turbine only. Note that the Division has not approved the test yet and based on the review of the test results, the test results may be revised due to errors or the Division may require further testing. If necessary, the permit will be reopened to revise the emission factor based on the Division's review of the performance tests.

VOC testing was conducted on the turbine alone on August 24 & 25, 2001 and on the HRSG stack (with fuel fired in the duct burner) on August 8 – 10, 2001. Based on the test results the source developed a correlation between VOC and load, similar to that used for Turbines 2 and 3. The correlation was submitted to the Division on November 8, 2001 and the correlation has been programmed into the data acquisition and handing system (DAHS) for Turbine 4. The Division has not reviewed the VOC testing or the VOC correlation and additional testing or changes to the correlation may be required based on the Division's review.

Monitoring Plan

The source will be required to monitor compliance with the NO_X and CO BACT and annual emission limitations using the CEMS as approved by the Division. Compliance with the VOC annual emission limitation shall be monitored using the VOC correlation programmed into the DAHS for the CEMS. Compliance with the annual SO_2 emission limits will be monitored using the continuous monitoring system required by 40 CFR Part 75 Appendix D. Compliance with the annual PM and PM_{10} emission limitations shall be monitored using emission factors and the heat input to the turbine and duct burner.

Compliance with the various short term PM and SO_2 requirements and the opacity requirements shall be presumed, in the absence of credible evidence to the contrary, whenever natural gas is used as fuel in the turbine and duct burner.

<u>Revision of Cooling Tower VOC Emission Limit</u>

The Division increased in the VOC emission limit from 2.3 tons/yr to 2.4 tons/yr as requested.

Insignificant Activity List (Appendix A of the Permit)

Based on comments made on the draft permit (received December 26, 2002), the following equipment/activities were added to the insignificant activity list:

Ammonia storage handling system (not a source of emissions)
Cooling water blowdown cooling tower (below APEN de minimis)
Two (2) gas line heaters (< 5 mmBtu/hr)

Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Ft. St. Vrain Station Operating Permit with the source's requested modifications. These changes are as follows:

Page following Cover Page

The citation (above "issued to" and "plant site location") on the page following the cover page provides the incorrect title for the state act. The title will be changed from "Colorado Air Quality Control Act" to "Colorado Air Pollution Prevention and Control Act". In addition, the dates were removed from the citation.

Changed the permit contact and the responsible official's title and phone number.

Added language specifying that the semi-annual reports and compliance certifications are due in the Division's office and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications.

Section I - General Activities and Summary

Conditions 13 and 17 in Condition 1.4 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22. The renumbering changes were necessary due to the addition of the Common Provisions requirements in the General Conditions of the permit.

The language in Condition 3.1 was revised to reflect language more consistent with other currently issued operating permits. The previous language regarding “contemporaneous modification of several sources” and “potential to emit” is misleading and is not addressed in other operating permits.

Based on comments made by EPA on another operating permit, the phrase “Based on the information provided by the applicant” was added to the beginning of Condition 4.1 (112(r)). In addition as requested by the source in their comments on the draft operating permit, received on December 26, 2002, added aqueous ammonia to the note indicating which compounds exceed the threshold level.

Removed Condition 4.2 (112(r) certification of risk management plans), since this is included in the annual compliance certification in Appendix C.

Added a “new” Section 5 for compliance assurance monitoring (CAM). As discussed previously, Turbine 4 is subject to CAM when operating in combined cycle mode. Turbines 2 and 3 are not subject to CAM because the low NO_X combustion design is not considered a control device, as discussed previously for Turbine 4 when operating in simple cycle mode.

<u>Section II - Specific Permit Terms</u>

Sections II.1 and 2– Turbines 2 and 3

Combined the provisions for simple cycle and combined cycle without supplemental fuel (Section II.1) and combined cycle with supplemental fuel (Section II.2) into one table. Provisions for Turbines 2 and 3 are now addressed in Section II.1 only.

Revised the language in the permit to indicate requirements that apply to only the turbine or the duct burner. Previously the permit language indicated that the requirement applied to the turbine and HRSG together. In the original permit, the Division indicated that from a practical standpoint the requirement applies to the combination, since the duct burner is not operated without the turbine and the duct burner and turbine share a stack.

Based on comments made by EPA in other permits, replaced “PSCo’s operating experience” with “good engineering practices” in Condition 1.1.1.1.

The definitions of startup and shutdown in Conditions 1.2.1 and 1.3.1 were revised so as not to conflict with the startup and shutdown definitions in the state statutes.

Removed the requirement in Conditions 1.2.1 and 1.3.1 to record the number of startups and shutdowns and the duration, since the source is already required to record the occurrence and duration of any startup and shutdown in Condition 5.2.5.

EPA has objected to defining normal operation to exclude startup and shutdown as they consider that startup and shutdown are a part of the normal operation of the emission unit. Therefore, the definition of normal operation has been removed from Conditions 1.2.1 and 1.3.1 and references to normal operation have been removed from the BACT limits.

Removed the language in Conditions 1.2.1 and 1.3.1 that specified that the CEM data shall, at the end of each hour, be summarized to generate the average turbine load. Due to revisions made to the NO_X and CO BACT limits during the processing of the original (i.e. current) operating permit, the average hourly turbine load is not necessary to monitor compliance with the NO_X and CO BACT limit.

Revised the monitoring language in Conditions 1.4.1, 1.4.3 (formerly Condition 2.3), 1.6.1, 1.6.3 (formerly Condition 2.5), 1.13, 1.14 and 1.1.5 to the following: "In the absence of credible evidence to the contrary, compliance with the standard will be presumed whenever pipeline quality natural gas is used as fuel in the turbines and duct burners."

Added the Reg 1 particulate matter standard for the turbine and duct burner combination. This requirement was previously overlooked. As calculated, the PM limit for the turbine and duct burner together is 0.1 lbs/mmBtu. Note that no Reg 1 PM standard was added for the duct burner itself since the duct burner would not be operated without the turbine. Compliance with the Reg 1 PM standard is presumed, in the absence of credible evidence to the contrary, whenever pipeline quality natural gas is used as fuel in the turbine and duct burner.

In the original permit, the NSPS GG SO_2 requirement (Condition 1.4.2) is written to imply that both the ppm and the fuel restriction apply to the turbines, while the source need only comply with one of the SO_2 provisions. Therefore, the permit was revised to reflect this. In addition, the monitoring language was changed to the following: "In the absence of credible evidence to the contrary, compliance with the standard will be presumed whenever pipeline quality natural gas is used as fuel in the turbines and duct burners."

Revised the language in Condition 1.4.4 (annual SO_2 emission limitations) to state that compliance will be monitored using the continuous monitoring system required by 40 CFR Part 75, rather than the continuous emission monitoring system required by Condition 1.10.

Revised the language in Conditions 1.5.1 (VOC BACT limit) and 1.5.2 (annual VOC emission limitations) to state that compliance will be monitored using the VOC correlation that has been programmed into the data acquisition and handling system rather than the continuous emission monitoring system required by Condition 1.10. In addition, the actual approved VOC correlation is based on heat input, not load. Therefore, the requirement in Condition 1.5.1 that states that CEM data shall be summarized each hour to calculate the average turbine load will be removed since the turbine load is not necessary to monitor compliance with the VOC BACT limit.

Revised the language for monitoring fuel consumption (Condition 1.8). The monitoring indicated that fuel use was monitored using an in-line fuel flowmeter that records hourly fuel consumption. 40 CFR Part 75 Appendix D requires that fuel consumption be monitored using an in-line fuel flowmeter that records hourly fuel consumption. For purposes of the annual fuel consumption requirements the hourly recording of fuel use is not necessary, so that language was removed. Note that under the Acid Rain portion of the permit (Section III), the source is required to meet the monitoring requirements in 40 CFR Part 75.

Revised the equations for calculating PM and PM_{10} emissions to calculate monthly emissions in units of tons/mo rather than lbs/mo.

The definition of “pipeline quality natural gas” in 40 CFR Part 72 was revised. Therefore, the change to this definition was made in Condition 1.9 of the permit. In addition, language was added to the permit to specify that natural gas that meets the provisions of Condition 1.9 is considered pipeline quality natural gas as defined in 40 CFR Part 72.

Revised the performance test language (Condition 1.12) regarding submittal of reports and scheduling of tests to the latest language.

Reworded the language in the opacity requirements (Conditions 1.13, 1.14, and 1.15) to more closely match the language in the regulation.

Added the NSPS opacity requirement to the permit. This requirement was inadvertently left out of the permit during original permit issuance.

Removed the requirement to submit a copy of the Acid Rain quarterly monitoring certification to the Division.

Section II.3 – Auxiliary Boiler

Revised Equation in Condition 3.1 to calculate emissions in tons/mo.

Revised the monitoring language in Conditions 3.3, 3.4 and 3.5 to the following: “In the absence of credible evidence to the contrary, compliance with the standard will be presumed whenever natural gas is used as fuel in the boiler.”

The language specifying the 20% and 30% opacity requirements (Conditions 3.4 and 3.5) were rewritten to more closely resemble the language in Regulation No.

1.

Section II.4 – Cooling Towers

Revised Equations in Condition 4.1 to calculate emissions in tons/mo.

The opacity requirements from Colorado Regulation No. 1, Section II.A.1 were included in the permit. The Division had previously not included this requirement in the operating permit since we believed that the cooling water and service water towers were most likely always in compliance with the opacity requirement. Although the Division considers that it is unlikely that the cooling/service water towers would violate the 20% opacity requirement, this requirement should have been included in the operating permit. The Division considers that the cooling water towers are, in the absence of credible evidence to the contrary, in compliance with the opacity requirements provided the cooling/service water towers and their associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

The opacity requirements in Colorado Regulation No. 1, Section II.A.4 were not included in the revised permit. Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling water towers. In addition, there is really no "startup" involved in operating a cooling water tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with these units.

Since compliance with the opacity requirement is based on drift eliminator maintenance, Condition 4.4 (drift eliminator inspection and maintenance) was removed.

Section II.5 – Continuous Emission Monitoring System

The requirement to record emissions of sulfur dioxide (5.1.10) and the corresponding note was removed from the continuous emission monitoring system requirements. This requirement was not in the original construction permit but was added by the Division. Under the Acid Rain requirements, the source is required to continuously monitor SO_2 emissions but the source is not required to install a traditional continuous emission monitoring system (CEMS), i.e. one that measures the pollutant concentration in the stack. Since Section II.5 addresses the traditional CEMS and other monitoring systems or information that is to be recorded on the data acquisition and handling system (DAHS) that was required by the construction permit. Since monitoring the SO_2 emissions continuously was not required by the construction permit and is required only to meet the Acid Rain requirements, the Division now considers that it is not necessary to address in Section II.5 of the permit, since the Acid Rain requirements are included in Section III of the permit.

The requirement to record emissions of VOC (5.1.8 & 9) and the corresponding note were removed from the continuous emission monitoring system requirements. Since the VOC concentration and emissions are not measured "in-stack" by a traditional CEMS the Division now believes it is probably not appropriate to include the VOC monitoring system with the traditional CEMS. It should be noted that the Division has approved the VOC correlation for Turbines 2 and 3.

Based on EPA comments on other permits, revised the language in Conditions 5.2.2 and 5.2.3 to state that approval must come from either the Division of the U.S. EPA, whichever is appropriate.

The equipment and QA/QC requirements (Condition 5.3) specify that both monitoring systems shall meet the requirements in Part 75, including performance specification requirements (Appendix A) but Appendix A contains no equipment or performance specification requirements for CO monitors. In addition, Part 75 contains requirements for certifications, monitoring plans and re-certifications that do not apply to the CO monitors. Therefore, the Division considers that it is more appropriate to require that the CO monitors meet the requirements in 40 CFR Part 60, except that the data replacement requirements in Part 75 will be used to replace CO data. In addition, this affects the "operating requirements" currently specified in Condition 5.2.1. These "operating requirements" are from Part 75 and the permit will be revised to specify that those "operating requirements" apply to the NO_X and diluent monitors and that the "operating requirements" from 40 CFR Part 60 Subpart A § 60.13(e) apply to the CO monitors.

The language in Condition 5.3.2 regarding the Part 75 CEMS was corrected. The language identified some sections of Part 75 that were not applicable to the units at Ft. St. Vrain.

Clarified that the data substitution requirements apply only to the annual limitations and corrected the source of the data substitution requirements (Subpart D rather than Appendix C). In addition, the second paragraph regarding manual data replacement until the DAHS is modified has been removed since modifications have been made and data substitutions are being made directly in the DAHS. In addition as discussed previously, since the SO_2 continuous monitoring system and data substitution requirements originate from the Acid Rain requirements and not the construction permit, the language regarding SO_2 data replacement has been removed.

Section II.6 – 20,000 Gallon Diesel Fuel Tank (Underground)

The current permit identifies a 20,000 gallon underground diesel fuel storage tank in the insignificant activity list. As part of the renewal processing, the Division requested information from PSCo as to when this tank commenced construction. Based on the information provided by PSCo in their response to comments submitted on December 26, 2002, this tank commenced construction after July 23, 1984 and is therefore subject to the requirements in 40 CFR Part 60 Subpart Kb. Since the tank is subject to the requirements in 40 CFR Part 60 Subpart Kb, the tank can no longer be considered an insignificant activity and even though emissions are below APEN de minimis levels, the tank is subject to APEN reporting and construction permit requirements in accordance with the "catch-all" language in Regulation No. 3, Part A, Section II.D.1 and Part B, Section III.D. Therefore, the tank has been removed from the insignificant activity list in Appendix A and added to the permit in Section II.6.

The tank is subject to the following applicable requirements:

- APEN reporting (Reg 3, Part A, Section II)
- 40 CFR Part 60 Subpart Kb, as adopted by reference in Colorado Regulation No. 6, Part A, specifically this unit is subject to the following:
    - Maintain records (per § 116b(b)) for the lifetime of the source (40 CFR Part 60 Subpart Kb § 116b9a))
    - Keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the vessel (40 CFR Part 60 Subpart Kb § 116b(b)).
    - Since this tank stores liquids with a maximum true vapor pressure less than 3.5 kPa, **this vessel is exempt** from the requirements of 40 CFR Part 60 Subparts A and Kb, except for §§ 60.116b9a) & (b) (40 CFR Part 60 Subpart Kb § 110b(c)).

The Division expects that the fuel usage for this tank will be low and that emissions will be well below APEN de minimis levels. Based on emissions, this tank would not be required to get a construction permit but must do so because the tank is subject to NSPS recordkeeping requirements. Therefore, the Division is not including an emission or processing limit in the operating permit. However, the tank is still subject to APEN reporting requirements and the permit will require that the quantity of fuel processed through the tank be monitored and recorded annually and that VOC emissions from tank breathing and working losses shall be determined annually using TANKS 4 or higher.

Section III – Acid Rain Requirements

Removed the requirement to submit a copy of the Acid Rain quarterly monitoring certification to the Division (Section 4).

Revised the DR title and phone number and changed the ADR (Section 1).

Section IV – Permit Shield

The citation for the permit shield is incorrect. The reference to Part A, Section I.B.43 should be Part A, Section I.B.44 and the reference to Part C, Section XIII should be Part C, Section XIII.B.

Based on comments made by EPA on another permit, the following statements were added after the introductory sentence in Section 1 “This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance”.

Based on comments made by EPA on another permit, the following phrase was added to the beginning of the introductory sentence “Based upon the information available to the Division and supplied by the applicant”

Section V - General Conditions

Added an “and” between the Reg 3 and C.R.S. citations in General Condition 3 (compliance requirements).

Added language from the Common Provisions (new condition 3). With this change the reference to “21.d” in Condition 20 (prompt deviation reporting) will be changed to “22.d”, since the general conditions are renumbered with the addition of the Common Provisions.

Removed the upset and breakdown provisions from Condition 4 (emergency provisions) since they are included in the Common Provisions.

Effective July 1, 2001, the Division’s permit processing, emission and APEN fees were increased. Therefore, the language in Condition 7 (fees) was changed to remove the specified fee and cite the state statute for the appropriate fee. In addition, the state statute will be cited rather than Reg 3.

The phrase “Part A” was added to the citation for Condition 13 (odor). Colorado Regulation No. 2 was revised and a Part B was added to address swine operations. Colorado Regulation No. 2, Part B should not be included as a general condition in the operating permit.

The citation in General Condition 16 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from “Reg 1” to “Reg 9”.

Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 28.

Appendices

First Page of Appendices – The phrase “except as otherwise provided in the permit” was added after the word “enforceable” in the disclaimer at the request of EPA.

Revised the description of the insignificant activity category for the emergency power generators (Reg 3, Part C, Section II.E.3.nnn) and stationary internal combustion engines (Reg 3, Part C, Section II.E.3.xxx).

Removed the 20,000 gal underground diesel storage tank from the insignificant activity list. It is now included in Section II of the permit.

Appendix B and C were replaced with revised Appendices.

The EPA addresses in Appendix D were corrected.

Added Acronyms for PPM (parts per million), PPMV (parts per million, by volume) and PPMVD (parts per million, by volume, dry) to Appendix E.